Appendix B: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR PETROLEUM REFINERIES

This appendix describes the emissions factors used and the control alternatives included and costed as part of this study to project the effect of various sulfur tax rates on petroleum refineries.

B.1 Emission Factors

A variety of processes or operations in a petroleum refinery may produce sulfur dioxide (SO_2) emissions. However, several minor refinery process sources represent only a small (and generally uncertain) fraction of total refinery SO_2 emissions. On the other hand, three major refinery operations produce significant SO_2 emissions and are treated as separate emissions sources: (1) catalyst regenerators, (2) Claus sulfur recovery plants, and (3) fuel combustion processes; i.e., heaters and boilers. As indicated in the estimated 1970 refinery sulfur balance shown in table B.1, the SO_2 emissions from these three operations account for 5.5, 4.5, and 3.3 percent, respectively, (for a combined total of about 13 percent) of the sulfur present in the input crude oil. About 78 percent of the input sulfur is distributed among marketed products (45.9 percent), recovered sulfur (26.7 percent), and waste water effluent (5.7 percent); the remaining 8.4 percent is unaccounted for and represents either S02 emissions by other refinery operations for which emission factors are unknown, or the result of using an unrepresentative value for the average sulfur weight percentage of the input crude oil.

B.1.1 Catalyst Regenerators

Catalysts used in catalytic crackers lose some of their activity after extended use and must be either regenerated or replaced. The regeneration process consists of oxidizing coke--which forms on the catalyst during cracking--to carbon monoxide. During regeneration, sulfur and sulfide deposits which also accumulate on the catalyst are oxidized to SO_2. Thus, catalyst regenerators, particularly those associated with Fluid Catalytic Cracker (FCC) units, are a major source of refinery sulfur emissions. As indicated in table B.2, sulfur emission rates from regenerators used with Thermofor Catalytic Cracking (TCC) units are considerably smaller.

Table B.1. Estimated U.S. petroleum refinery sulfur balance--1970

	Barrels (thousand)*	Average sulfur weight (percent)	Sulfur content (thousand tons)		Percent
Input					
Crude oil	3,967,500	0.81†	4,747		100
Disposition					
Products marketed					
Gasoline	2,100,000	0.03	2,178		45.9
Kerosene	96,000	0.05	95		
Jet fuel	302,000	0.3 ††	128		
Distillate oil¶	897,000	0.3 **	408		
Residual oil¶	206,667	1.6 **	533		
Petroleum coke	11,300#	1.8 §	212		
Asphalt	26,500#	3.0 §	795		
Water effluent§	---	---	270		5.7
Sulfur recovered	----	---	1,269		26.7
Refinery emissions§§	---	---	633		13.3
Residual oil burned	43,323	1.8	159	3.3	
Claus plant	---	--	212	4.5	
Fluid catalytic cracker (FCC) regenerators‡	---	---	256	5.4	
Thermofor catalytic cracker (TCC) regenerators‡	---	---	6	0.1	
Total	---	---	4,350		91.6
Unaccounted for	---	---	397		8.4

* Mineral Industry Survey, U.S. Department of Interior, December 23, 1971.

† Estimated average for domestic and imported crude processed in U.S. refineries.

‡ From catalyst coke burning.

§ Estimated.

¶ Excludes imports of 557,000 thousand barrels.

10^3 Ton (coke 5.0 bbl/ton; asphalt 5.5 bbl/ton).

**OAP Data file of Nationwide Emission for 1970, July 1972.

††Domestic airline specification; actual may be lower.

‡‡"Sulfur Content of Crude Oils of the Free World," Bureau of Mines, RI 7059, 1967.

§§Research Triangle Institute.

Table B.2. Sulfur emission factors for petroleum refineries

Emissions source	Sulfur emission factors (lb/thousand barrels of fresh feed or oil burned, as appropriate)
Catalyst regenerators	
Fluid catalytic cracker	262
Thermofor and Houdriflow catalytic cracker	30
Refineries without Claus plants	720
Refineries with Claus plants	72
Fuel combustion	68

Source: Compilation of Air Pollutant Emission Factors Environmental Protection Agency, Research Triangle Park, N.C., February 1972, pp. 9-1, 9-2.

5.1.2 Claus Plants

Many refinery processes produce off-gases which contain hydrogen sulfide (H2S). All plants strip the H2S (usually in excess of 95 percent) from the off-gases before they are burned in process heaters and boilers. If the refinery does not have a Claus plant to convert the stripped H2S to sulfur, the H2S stream is flared to the atmosphere and produces large amounts of S02. It has been assumed that an average 2-stage Claus plant can provide about a 90-percent conversion of the input H2S to elemental sulfur, with the remaining unconverted sulfur being emitted as SO2. An average 4-stage Claus plant is assumed to provide upwards of 95-percent conversion of H2S. Recently developed "tail gas modifications" of the 4-stage Claus unit provide a 99.9-percent conversion of input H2S to elemental sulfur.

At present, not all refineries have Claus plants, but those that do generally have 2-stage plants.

B.1.3 Fuel Combustion

Much of the fuel required by refinery process heaters and boilers is produced by the refinery itself. Most of the SO2 emissions from refinery combustion sources result from the use of liquid fuels such as low value distillate and residual oils. Because of their relatively high sulfur concentrations, these fuels are frequently unsuitable for marketing. As indicated in table B.1, more than 43 million barrels of residual fuel oil were burned in U.S. refineries during 1970. Using an estimated sulfur concentration of 1.8 percent by weight, residual fuel oil combustion in refineries resulted in the release of about 159,000 tons of sulfur to the atmosphere during 1970. Combustion of refinery gases also results in SO_2 emissions; however, these gases are generally scrubbed for removal of sulfur values prior to burning and thus produce relatively little SO_2 in comparison with residual fuel oil combustion.

Sulfur emissions factors for the three refinery sources identified above were derived from the data shown in table B.1, and are shown in table B.2.

B.2 Sulfur Emissions Control Alternatives and Costs

Costs as a function of capacity have been estimated for controlling sulfur emissions from the three emission sources discussed above. In most cases, several techniques for controlling emissions at each source--each technique representing a unique level of control--have been costed. The control cost estimates were based on previous studies for EPA and private communications with EPA personnel. Table B.3 summarizes the alternatives available for controlling sulfur emissions which appear to be most feasible by 1978, and their removal efficiencies by emissions source.

B.2.1 Catalyst Regenerators

Hydrodesulfurization of catalytic cracker feedstock was costed as the most economical technique for reducing sulfur emissions from catalyst regenerators. Catalytic crackers are fed by vacuum gas oil from vacuum distilling units and/or heavy gas oil from atmospheric crude topping units. Hydrodesulfurization processes now in commercial use are effective in removing up to about 95 percent of the sulfur in these oils. Since most of the sulfur present in catalytic cracker feedstock is passed on to the cracked products and only a small fraction is picked up by the catalyst and emitted during catalyst regeneration, both product desulfurization and reduction in regenerator emissions will result from application of this control technique.

Hydrodesulfurization of vacuum gas oil and heavy gas oil involve high-temperature, high-pressure hydrogen treatments in the presence of a catalyst.

Table B.3. Sulfur emission control alternatives for petroleum refineries

Emissions source	Abbreviation*	Alternative	Control alternative	Removal efficiency (percent)
Catalyst regenerator				
FCC	PR-CR	1	Hydrodesulfurization of catalytic cracker feedstock	90
TCC & HCC	PR-CR	2		90
Refineries without Claus plant	PR-S		Two-stage Claus plant	90
	PR-S	1	Four-stage Claus plant	95
	PR-S	3	Four-stage Claus plant with tail gas unit	99.5
Refineries with Claus plant	PR-S	4	Add two additional conversion stages to Claus plant	95
	PR-S	5	Add two additional conversion stages to Claus plant plus tail gas unit	99.5
Fuel oil combustion	PR-FC	1	Hydrodesulfurization of residual fuel oil	90

*Abbreviations index to Table B.4.
Source: Research Triangle Institute.

The hydrodesulfurization process generally employs a fixed bed catalytic reactor and a regenerable catalyst. Sulfur compounds are converted to H_2S in the reactor and drawn off with other overhead gases. The H_2S is subsequently separated from the other gases by amine scrubbing and directed to a sulfur plant for conversion to elemental sulfur. The liquid bottoms constitute the desulfurized product which, in this case, will be fed to the catalytic cracker. In addition to sulfur removal, hydrogen treating of catalytic cracker feedstock will reduce coke production in the cracker by 25 to 30 percent and increase gasoline yield. In the present analysis, it was assumed that the hydrodesulfurization process removed 90 percent of sulfur present in the cracker feedstock and effects a similar reduction in sulfur emissions to the atmosphere from the catalyst regenerator.

Annualized costs for several refinery capacities are presented in table B.4 along with emissions data.

Table B.4. Sulfur emission control costs for petroleum refineries

Control alternative by unit process	Control costs (thousand dollars) Investment				Control costs (thousand dollars) Annualized total cost of control				Annual emissions after control (tons)				Annual additional recovered sulfur after control (tons)			
	5,000*	50,000*	100,000*	500,000*	5,000*	50,000*	100,000*	500,000*	5,000*	50,000*	100,000*	500,000*	5,000*	50,000*	100,000*	500,000*
PR-CR(1)	$122	$ 560	$ 900	$2,500	$432	$2,920	$5,200	$24,000	9	84	169	840	532	5,325	10,698	53,250
PR-CR(2)	122	560	900	2,500	432	2,920	5,200	24,000	11	14	29	143	432	5,325	10,698	53,250
PR-S(1)	170	430	600	1,460	23	82	121	421	65	649	1,300	6,495	585	5,846	11,691	58,459
PR-S(2)	180	500	720	1,900	31	108	160	555	32	325	650	3,248	618	6,170	12,341	61,706
PR-S(3)	360	1,000	1,420	3,800	65	227	337	1,168	1	5	13	65	649	6,490	12,978	64,889
PR-S(4)	10	46	120	440	8	26	39	134	32	325	650	3,248	33	324	650	3,247
PR-S(5)	160	380	720	1,900	34	119	177	613	1	5	13	65	64	644	1,287	6,430
PR-FC	30	90	135	375	59	433	806	3,539	6	59	119	594	53	535	1,070	5,346

*Plant capacity, barrels per day.

Source: Developed by Research Triangle Institute for this study from data presented in:

1. Research Triangle Institute, Control Technology for Sulfur Oxide Pollutants, 2nd ed., November 20, 1972.
2. Aalund, L., Hydrodesulfurization Technology Takes on the Sulfur Challenge," Oil and Gas Journal, September 11, 1972, p.79.
3. Barry, B.B., "Reduce Claus Sulfur Emission," Hydrocarbon Processing, April 1972, p. 102.
4. "Characterization of Claus Plant Emissions," Preliminary draft of final report prepared for the Environmental Protection Agency by Process Research, Inc., Cincinnati, Ohio, September 1972.

As shown in the table, a refinery with a capacity of 5,000 bbl/d could reduce fluid catalytic cracker emissions to 9 tons of sulfur annually with an annualized cost of $432,000. The precontrol level is 90 tons annually (i.e., 9 ÷ (1 (1 - removal efficiency of 90 percent)). A refinery would control sulfur emissions from this source when the cost of control plus the tax rate times the remaining emissions was less than the tax times uncontrolled emissions. For this example refinery, this condition would obtain for tax rates in excess of 267 cents per pound of sulfur emissions since:

$$\$432{,}000 + X\ (9) = X\ (90)$$

$$X = \$5{,}333 \text{ per ton or } \$2.67 \text{ per pound}$$

where

X = tax rate per ton of sulfur emissions.

B.2.2 Claus Plants

Annualized costs for Claus plants were prepared for two cases:

(1) In refineries where there is no present Claus plant, there are three possible alternatives: (a) a 2-stage Claus plant, (b) a 4-stage Claus plant, or (c) a 4-stage Claus plant with a tail gas unit.

(2) In refineries where there is an existing 2-stage (assumed) Claus plant, there are 2 possible alternatives: (a) addition

of two additional conversion stages to the existing plant, or (b) the addition of 2 or more conversion stages plus a tail gas unit.

Annualized costs that reflect these alternatives are presented in table B.4 along with emissions data.

B.2.3 Fuel Combustion

Direct desulfurization of residual fuel oil was selected as the most economical technique for controlling sulfur emissions from refinery combustion. Hydrodesulfurization processes applicable to residual fuel oils are similar to those used with vacuum gas oil except that they are more severe and require highly selective, well-designed catalysts which are resistant to metal deposits. Unlike catalysts used in vacuum gas oil hydrodesulfurization, these catalysts normally cannot be regenerated and must be replaced. There are a variety of direct hydrodesulfurization processes used commercially to reduce the sulfur content of marketed residual fuel oils. Sulfur reductions in the 80- to 95-percent range can be achieved by these processes. Despite recent advances, residual fuel oil desulfurization processes are still relatively expensive and are used only when final fuels must be low in sulfur or when the feedstock is of high sulfur content. Because of the high costs involved, desulfurization of residual fuel oil consumed by refineries is not now being practiced.

Residual fuel oil hydrodesulfurization is assumed to remove and recover 90 percent of the sulfur present in the oil, thereby reducing sulfur emissions from refinery residual fuel oil combustion sources to 10 percent of the uncontrolled level. Annualized costs for residual fuel oil desulfurization are presented in table B.4 along with emissions data.

B.2.4 Emissions Reductions and Costs

Industry cost of control functions have been developed based on the costs and effectiveness of the control alternatives costed above and a listing of the nation's petroleum refineries which includes relevant process parameters for emission and control cost estimation. These functions are minimum cost functions for achieving sulfur emissions reductions from the petroleum refining industry. Table B.5 summarizes the refinery data.

The long-run industry total and marginal costs of sulfur emissions reductions are shown in figures B.1 and B.2. The total costs (LTC) increase at an increasing rate throughout the range for which data are available. The marginal costs (LMC) increase with increases in emissions reductions. Beyond reductions of 250,000 tons, the marginal cost function rises quite rapidly.

Table B.5. Size distribution of petroleum refineries (number of refineries)

Capacity (barrels per day)	Crude	Catalytic cracking: Fluid	Catalytic cracking: Thermofor & Houdriflow
0 - 10	91	16	11
11 - 20	38	33	10
21 - 30	27	23	8
31 - 40	17	14	4
41 - 50	21	10	
51 - 60	11	9	
61 - 70	6	6	
71 - 80	9	4	
81 - 90	13	2	
91 - 100	1	1	
101 - 110	4	2	
111 - 120	3		
121 - 130	1	1	1
131 - 140	5	1	
141 - 150	1	1	
151 - 160	5	2	
161 - 170	3		
171 - 180		2	
181 - 190	2		
191 - 200	5		
201 - 220		1	
221 - 240			
241 - 260	2		
261 - 280			
281 - 300	1		
301 - 325	2		
326 - 350	2		
351 - 375			
376 - 400			
401 - 425			
426 - 450	1		

Source: The Oil and Gas Journal, April 6, 1970, pp. 121-41.

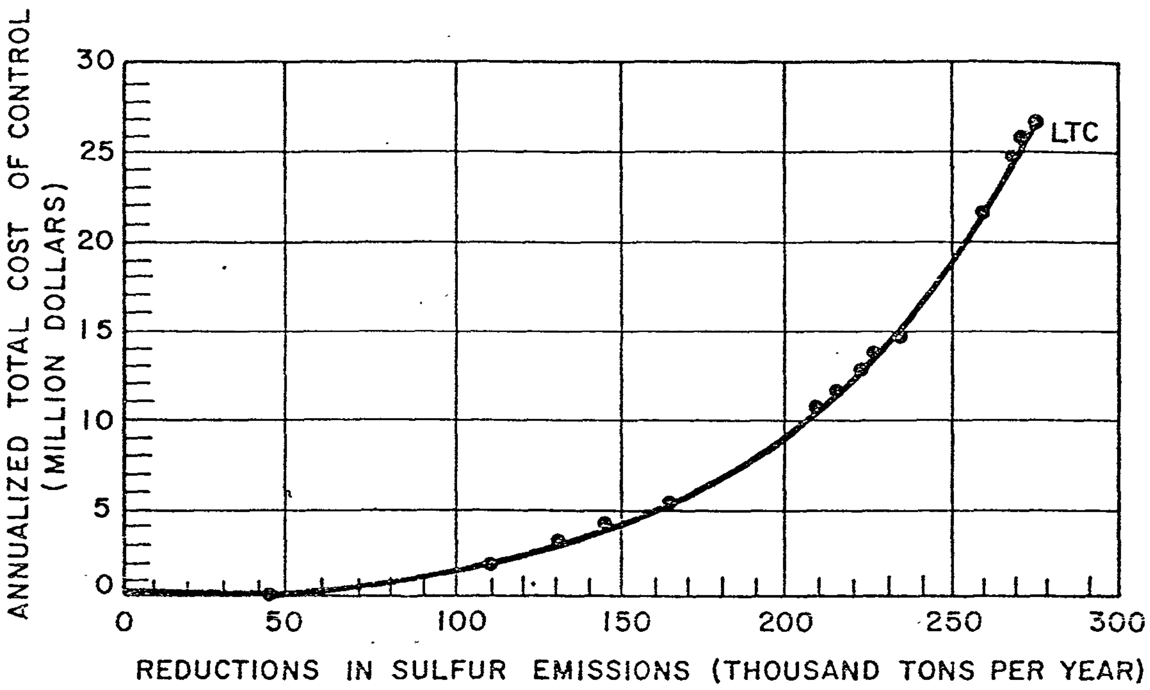

Figure B.1. Total cost* of reductions in sulfur emissions: petroleum refineries--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

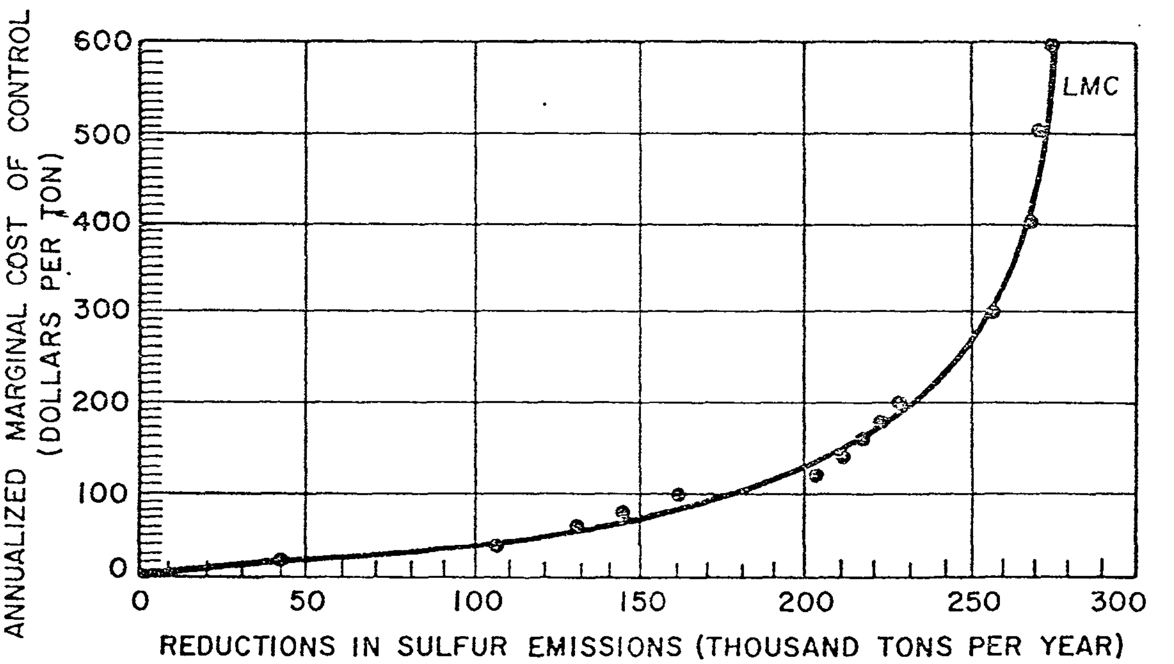

Figure B.2. Marginal cost* of reductions in sulfur emissions: petroleum refineries--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

Appendix C: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR SULFURIC ACID PRODUCERS

This appendix describes the emission factors used and the control alternatives included and costed as part of this study to project the effect of various sulfur tax rates on sulfuric acid plants.

C.1 Emission Factors

Sulfur emissions from the production of sulfuric acid by the contact process are of two types. One type is gaseous, as sulfur dioxide (SO_2), which results from the incomplete oxidation of SO_2 to sulfur trioxide (SO_3) in the conversion step. The unconverted SO_2 is not absorbed in the weak sulfuric acid during the absorption step and is emitted in the absorption tower tail gas. The other type of sulfur emission is acid mist which emerges from the absorption tower entrained in the tail gas.

The actual rate of SO_2 emissions from a particular plant depends upon the conversion efficiency of SO_2 to SO_3 and the level of production. For this analysis, a conversion efficiency of 97 percent was used. This results in an emission factor of 40 pounds of SO_2 per ton of 100 percent acid produced.

The quantity of acid mist emissions depends primarily on whether normal sulfuric acid (< 99 percent acid) or oleum (100 percent acid plus excess dissolved SO_3) is being produced. For normal sulfuric acid production, an emission factor of 2.5 pounds of acid mist per ton of acid produced was used; while for oleum production, a factor of 7.5 pounds of acid mist per ton of acid production was used.

Fifty percent by weight of SO_2 is sulfur and approximately 32 percent by weight of acid mist is sulfur.

New Source Performance Standards limit SO_2 emissions to a maximum of 4 pounds per ton of acid produced, and limit particulate (acid mist) emissions to a maximum of 0.15 pound per ton of acid produced. The emission factors are summarized in table C.1.

C.2 Sulfur Emissions Control Alternatives and Costs

The control techniques for reducing sulfur emissions from sulfuric acid plants vary depending on whether gaseous or particulate emissions are being controlled. All the systems costed result in the recovery of sulfur in the form of increased sulfuric acid production.

Table C.1. Sulfur emission factors for sulfuric acid plants

Emissions source	Sulfur emission factors (lb/ton of acid production)
Gaseous	20.00
Mist, normal plants	1.28
Mist, oleum plants	1.28

Source: Compilation of Air Pollutant Emission Factors, U.S. Environmental Protection Agency, Research Triangle Park, N.C., February 1972, pp. 5-18.

Table C.2 summarizes the alternatives available for controlling sulfur emissions and their removal efficiencies by emissions source. These control alternatives represent those that appear most feasible by 1978.

C.2.1 Gaseous Emissions Control

Alternatives for gaseous emissions control have been developed and technically demonstrated: the best are the dual absorption and the sodium sulfite scrubbing techniques. The dual absorption technique requires the interposition of an intermediate absorption tower in the traditional process configuration. By interposing this second absorption tower, overall conversion of SO_2 to SO_3 is increased from 97 to 99.7 percent, Thus, SO_2 emissions are reduced by 90 percent and production of sulfuric acid is increased by nearly 3 percent without additional raw materials.

In the sodium sulfite scrubbing technique, unreacted SO_2 in the exhaust gas is reacted with sodium sulfite to form certain thermally reactive crystals which when heated liberate SO_2. The liberated SO_2 is fed back into the acid plant to increase the yield of the plant by about 3 percent. The control efficiency of this system is about 95 percent,

New sources are expected to meet New Source Performance Standards for gaseous emissions (4 pounds SO_2 per ton of acid) by using dual absorption. The incremental costs necessary for the new sources to use sodium sulfite scrubbing instead of dual absorption are slightly less than those that can

Table C.2. Sulfur emissions control alternatives for sulfuric acid plants

Emissions source	Abbreviation*	Alternative	Control alternative	Removal efficiency (percent)
		EXISTING SOURCES		
Gaseous, all plants	SA-A	1	Dual absorption	90
Gaseous, all plants	SA-A	2	Sodium sulfite scrubbing	95
Mist, normal plants	SA-B	2	Dual mesh pad demister	90
Mist, normal plants	SA-B	1	Tubular fiber demister	99.5
Mist, oleum plants	SA-C	1	Dual mesh pad demister	75
Mist, oleum plants	SA-C	2	Tubular fiber demister	99.5
		NEW SOURCES		
Gaseous, all plants	SAN-A	1	Sodium sulfite scrubbing	60
Mist, normal plants	SAN-B	1	Tubular fiber demister	95

*Abbreviations index to table C.3.

Source: Research Triangle Institute.

be calculated for the existing sources since some economies are achieved in installing these devices on new plants as compared with adding them to existing plants.

C.2.2. Mist Control

Acid mists can be controlled with filter devices called demisters. Two effective demisters are currently available. These are the dual mesh pad demister and the tubular fiber demister which achieve control efficiencies of 90 and 99.5 percent, respectively, in nonoleum plants; the corresponding control efficiencies for oleum plants are 75 and 99.5 percent.

New sources are expected to meet the New Source Performance Standards for mist emissions (0.15 pound of mist per ton of acid) by dual mesh pad demisters in the normal acid plant and tubular fiber demisters in the oleum plants. The control alternatives, their costs, and effectiveness in controlling SO_2 emissions from sulfuric acid production were derived from several studies for EPA as well as private communications with EPA personnel. These costs have been estimated on an annualized basis for representative plant sizes (table C.3). Interpolation is used to derive cost estimates for plant sizes other than those estimated for the representative plant sizes.

As shown in table C.3 for an annualized cost of $67,000, emissions from a 50-ton-per-day plant can be reduced to 19 tons of sulfur annually. The pre-control level is 190 tons annually (i.e., 19 ÷ (1 - removal efficiency of 90 percent)). A plant would control sulfur emissions using dual absorption when the cost of control plus the tax rate times the remaining emissions was less than the tax times uncontrolled emissions. For this example plant, that would be for tax rates greater than 20 cents per pound of sulfur emissions since:

$$\$67,000 + X\ (19) = X\ (190)$$

$$X = \$391 \text{ per ton or 20 cents per pound}$$

where

X = tax rate per ton of sulfur emissions.

C.2.3. Emissions Reductions and Costs

Industry cost of control functions have been developed based on the costs and effectiveness of the control alternatives costed above and a listing of the nation's sulfuric acid plants using the contact process. This listing includes relevant plant information for emissions and cost estimation; the size and type distribution is shown in table C.4. The functions are minimum cost functions for achieving sulfur emissions reductions from the sulfuric acid industry.

The long-run industry total and marginal costs of sulfur emissions reductions are shown in figures C.1 and C.2. The total costs (LTC) increase at a moderately increasing rate until the higher levels of emissions reductions are reached. This is reflected in the marginal cost curve (LMC) which rises rapidly after reductions of about 285,000 tons are achieved.

Table C.3. Sulfur emissions control costs for sulfuric acid

Control alternative by unit process	Control costs (thousand dollars)								Annual emissions after control (tons)				Annual additional recovered sulfur after control† (tons)			
	Investment				Annualized											
	50*	250*	750*	1500*	50*	250*	750*	1500*	50*	250*	750*	1500*	50*	250*	750*	1500*
	EXISTING SOURCES															
SA-A(1)	$242	$636	$1,230	$1,864	$67	$186	$383	$612	19	94	281	563	169	844	2,531	5,063
SA-A(2)	295	776	1,500	2,273	88	259	563	937	9	47	141	281	178	891	2,672	5,344
SA-B(1)	16	40	105	194	5	13	35	64	0.8	3.8	11.5	23.0	6.9	34.5	103.3	206.6
SA-B(2)	43	114	245	396	12	33	74	124	0.0	0.2	0.6	1.1	7.7	38.1	114.2	228.5
SA-C(1)	16	40	105	194	5	13	35	64	5.7	28.7	86.1	172.7	17.3	86.1	258.3	516.1
SA-C(2)	43	114	245	396	12	33	74	124	0.8	3.8	111.5	23.0	22.2	110.0	332.9	665.8
	NEW SOURCES															
SAN-A(1)	272	751	1,500	2,321	21	73	180	325	9	47	141	281	9	47	141	281
SAN-B(1)	23	62	105	140	7	20	39	60	0.0	0.2	0.6	1.1	1	3.6	10.9	21.9

*Plant size in tons of sulfuric acid processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Developed by Research Triangle Institute from data presented in:

1. Background Information for Proposed New Source Performance Standards, APTD-0711, Environmental Protection Agency, August 1971.
2. Chemico Construction Corporation, Engineering Analysis of Emissions Control Technology for Sulfuric Acid Manufacturing Processes, NAPCA, March 1970 (NTIS No. PB-190 393).
3. Boys, Paul A., Environmental Protection Agency (private communication), November 1972.
4. Buckhardt, D.B., VonBree, Inc. (private communication), October 1972.
5. Walsh, R., Environmental Protection Agency (private communication), September 1972.
6. Carey, D., Environmental Protection Agency (private communication), September 1972.

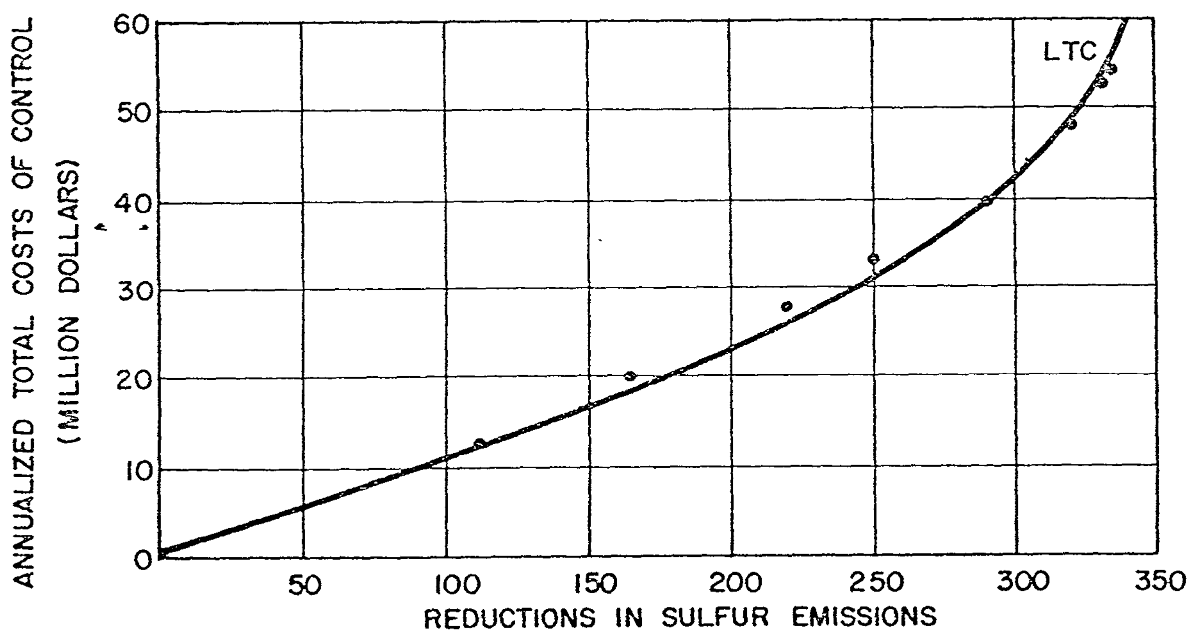

Figure C.1. Total cost* of reductions in sulfur emissions: sulfuric acid producers (*does not include emissions tax payments) (Source: Research Triangle Institute).

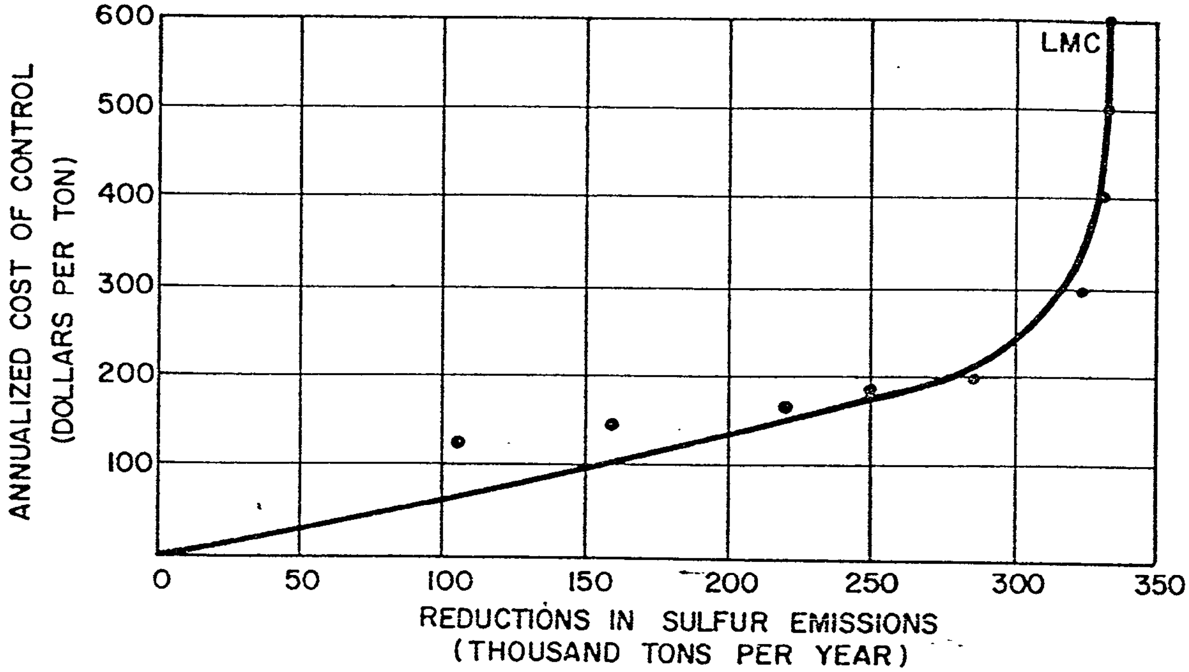

Figure C.2. Marginal cost* of reductions in sulfur emissions: sulfuric acid producers--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

Table C.4. Size distribution of sulfuric acid plants

Capacity*	Normal Plants	Oleum Plants
less than 100	16	2
100-199	24	9
200-299	18	10
300-399	12	6
400-499	14	7
500-749	21	10
750-999	14	6
1,000-1,499	5	2
1,500 & over	28	4

*Plant size in tons of sulfuric acid processed per day.

Source: Research Triangle Institute.

Appendix D: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR PRIMARY NONFERROUS SMELTERS

This appendix discusses the emission factors used, and the control alternatives included and costed as part of this study to project the effect of various sulfur tax rates on primary nonferrous smelters.

D.1 Emission Factors

D.1.1 Copper Smelters

The three principal sources of sulfur diodixe (SO_2) emissions from copper smelters are roasters, reverberatory furnaces, and converters. Total emissions from all these sources amount to approximately 1,250 pounds of SO_2 for every ton of ore concentrate charged. Of the 15 operating smelters, 7 do not use a roaster but instead charge the reverberatory furnace directly with the ore concentrate. The roaster, where used, produces about 40 percent of total SO_2 emissions; the reverberatory furnace, 20 percent; and lastly the converter, 40 percent. If no roaster is used, the reverberatory furnace produces about 30 percent of the total emitted and the converter the remaining 70 percent. Sulfur emission factors are shown in table D.1.

Table D.1. Sulfur emission factors for copper smelters

Emissions source	Emission factor (pounds of sulfur per ton of ore concentrate)
Roaster	249
Reverberatory furnace (w/o roaster)	186
Reverberatory furnace (w/roaster)	125
Converter (w/o roaster)	435
Converter (w/roaster)	249

Source: Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Copper Industry, September 1962.

Table D.2. Sulfur emission factors for zinc smelters

Emissions source	Emission factor (pounds of sulfur per ton of ore concentrate)
Roaster (dead roast)	600.0
Sinterer (after roast)	Negligible
Sinterer (no roast)	630.0
Reduction	Negligible

Source: Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Zinc Industry, April 1971.

D.1.2 Zinc Smelters

Totally uncontrolled emissions from zinc smelters amount to about 1,100 pounds of SO_2 per ton of ore charged. Where roasting takes place, either alone or in conjunction with sintering, it accounts for virtually 100 percent of the SO_2 emitted. Where the zinc concentrate is processed solely in a sintering machine (actually it is a combination roaster-sinterer), this unit process produces 100 percent of all SO_2 emitted in the smelting operation. Table D.2 presents sulfur emission factors for zinc smelters.

D.1.3 Lead Smelting

Totally uncontrolled emissions from lead smelters amount to about 660 pounds of SO_2 per ton of ore charged. Roughly 98 percent of this total is emitted in the sintering step, with the remaining 2 percent emitted from blast furnaces. Table D.3 presents emission factors for lead smelters.

D.2 Sulfur Emissions Control Alternatives and Costs

The SO_2 control methods that are likely to be employed in the near future are:

(a) sulfuric acid plants,

(b) lime and limestone scrubbing,

(c) amine absorption,

(d) ammonia scrubbing, and

(e) sodium sulfite-bisulfite absorption.

The best choice of a control technique from the standpoint of well-developed technology is the sulfuric acid plant. However, it requires that the concentration of SO_2 in the feed gas be at least 3.5 percent for a single

Table D.3. Sulfur emission factors for lead smelters

Emissions Source	Emission factor (pounds of sulfur per ton of concentrate)
Roaster-sinterer	472
Blast furnace or dross reverberatory furnace	58

Source: Compilation of Air Pollutant Emission Factors. U.S. Environmental Protection Agency, pp. 7-8.

contact plant and 5 percent for a double contact plant. Unfortunately, some tail gas streams, notably those from reverberatory furnaces, are normally below these minimum concentrations. For this reason, two methods that can be used on dilute streams are considered in this analysis. One is limestone scrubbing, which has an 85 to 90 percent efficiency and a throwaway byproduct; the other is amine scrubbing, which can achieve 99 percent efficiency and produces concentrated SO_2 which may either be sold as is or mixed with lean tail gas streams to enrich the input stream to a sulfuric acid plant. Control cost estimates were based chiefly on previous studies for EPA and private communications with EPA personnel.

In certain instances, process modification or replacement was incorporated into the design of control alternatives. The purpose, where this alternative was chosen, was to produce waste gas richer in SO_2 and more amenable to the application of control techniques that produce a marketable byproduct.

The control alternatives costed represent those that appear most feasible by 1978. Other alternatives may develop in response to the demand for more cost-effective methods of smelter sulfur emissions control as a result of an emissions tax. Those alternatives, of course, could not be included in the analysis,

D.2.1 Copper Smelters

As stated above, gas streams with an SO_2 concentration of less than 3.5 percent are not amenable to direct input into a sulfuric acid plant.

Available data indicate that roaster off-gases average about 8 percent SO_2, reverberatory furnaces 1 to 2 percent, and converters about 7 percent.

Where a tail gas stream of SO_2 concentration less than 3.5 percent exists, there are essentially two control alternatives. One is to concentrate the SO_2 and then input this into an acid plant, The other is to scrub the lean gas and forego the recovery of economically valuable sulfur products.

The alternative costed to provide a method for concentrating SO_2 is amine absorption, In this technique, the low SO_2 concentration gas stream is passed through an absorption bed on which up to 99 percent of the SO_2 is absorbed. This bed can then be stripped, yielding an almost pure stream of SO_2. This SO_2 can be fed into an acid plant either alone or in combination with off-gases from other smelting until processed.

The alternative costed to scrub the weak SO_2 stream is wet limestone scrubbing. In this system, the gas stream is passed through a wet limestone slurry, the end product of which is solid calcium sulfate ($CaSO_4$) which must be disposed of, there being no commercial use available. An SO_2 removal efficiency of 90 percent may be expected from the application of wet limestone scrubbing.

Where a sufficiently concentrated gas stream was available, a sulfuric acid plant was costed as the control alternative. It must be remembered, however, that a sulfuric acid plant does not provide 100 percent control of the input SO_2. For the purposes of this analysis, it was assumed that a single-absorption sulfuric acid plant will emit approximately 2,000 parts per million (ppm) SO_2 in its off-gas stream; while a double-absorption plant will emit about 500 ppm SO_2. Table D.4 indicates the expected removal efficiencies of single- and double- absorption systems as a function of the input SO_2 concentrations. Double absorption can reduce SO_2 emissions below those effected by single absorption, but, of course, at a significantly higher cost.

Three additional control alternatives are possible. Two alternatives are the installation of either (a) single- or (b) double-absorption acid plants where none now exist; the third alternative is the addition of a dual absorption capability to an existing single-absorption plant.

For the purposes of this analysis, the 15 existing copper smelters are characterized by two parameters. These are: (1) the unit processes employed and (2) the presence or absence of an acid plant (it should be noted that all

Table D.4. Sulfur dioxide removal efficiencies of sulfuric acid plants as a function of input concentrations for single- and double-absorption systems

Input SO_2 concentration percent	Removal efficiency (percent)	
	Single absorption	Double absorption
3.5	94.3	98.6
5.0	96.0	99.0
7.5	97.4	99.3
10.0	98.0	99.5

Source: Research Triangle Institute.

existing smelter acid plants are of the single contact variety and that no smelters practice limestone scrubbing). Thus, a copper smelter can have "green feed" to the reverberatory furnace (i.e., no roaster) plus converters, or it can have "conventional feed" (i.e., ore concentration to a preliminary roaster) plus reverberatory furnaces and converters; for each of these plant types, there may or may not be an existing acid plant. These four plant types are summarized in table D.5 along with an abbreviation for each type which will be used in subsequent discussion. Each copper smelter in the plant inventory has been identified as being one of the four plant types.

Table D.5. Copper smelter plant types

Plant type	Abbreviated designation or
Green feed (no acid plant)	Cu-A
Green feed (acid)	Cu-B
Conventional feed (no acid plant)	Cu-C
Conventional feed (acid plant (on roaster or converters))	Cu-D

Source: Research Triangle Institute.

Table D.6. Sulfur emission control alternatives for copper smelters

Plant type	Alternative	Control alternative	Removal efficiency (percent)
Cu-A	1	Double-absorption acid plant on converters	68.6
	2	Double-absorption acid plant on converters & limestone scrubbing on reverberatory furnace	95.6
	3	Double-absorption acid plant on converters & amine absorption on reverberatory furnace (concentrated SO_2 to double-absorption acid plant)	97.5
Cu-B	1	Limestone scrubber on reverberatory furnace	95.3
	2	Amine absorption on reverberatory furnace (concentrated SO_2 to an acid plant)	97.2
Cu-C	1	Double absorption on converter & roaster	78.6
	2	Double absorption on converter, roaster, and reverberatory furnace (amine absorber concentrates the reverberatory furnace flow)	98.2
Cu-D	1	Double-absorption acid plant on either roaster or converters	78.2
	2	Double-absorption acid plant on either roaster or converter & amine absorber on reverberatory furnace (concentrated SO_2 stream to new double-absorption plant)	97.9

Source: Research Triangle Institute.

Sets of SO_2 control alternatives were selected independently for each plant type. These alternatives are listed in summary fashion in table D.6.

Table D.7 presents a summary of the costs and emissions associated with each control alternative for selective plant sizes.

D.2.2 Zinc Smelters

Zinc smelters can be categorized into three plant types:

(a) Combination roaster-sintering machine (downdraft type)--
no acid plant,

Table D.7. Sulfur emission control costs for copper smelters

Control alternative by unit process	Control costs (million dollars)						Annual emissions after control (thousand tons)			Annual additional recovered sulfur after control† (thousand tons)		
	Investment			Annualized								
	100*	200*	600*	100*	200*	600*	100*	200*	600*	100*	200*	600*
Cu-A(1)	$ 6.3	$ 9.8	$19.6	1.37	2.17	4.30	13.3	26.5	79.5	29.0	58.1	174.2
Cu-A(2)	9.2	14.3	28.6	2.52	4.01	7.00	1.8	3.7	11.0	29.0	58.1	174.2
Cu-A(3)	13.8	21.4	42.8	3.00	4.75	9.37	1.1	2.1	6.3	41.3	82.5	247.5
Cu-B(1)	2.9	4.5	9.0	1.15	1.84	3.67	2.0	4.0	12.1	0	0	0
Cu-B(2)	10.0	15.5	31.0	2.13	3.38	6.75	1.2	2.4	7.3	12.4	24.9	74.7
Cu-C(1)	7.2	11.2	22.4	1.52	2.41	4.81	9.1	18.1	54.5	33.2	66.4	199.1
Cu-C(2)	15.3	23.7	47.4	3.15	4.99	9.95	0.7	1.5	4.4	41.5	83.0	249.1
Cu-D(1)	4.5	7.0	14.0	0.96	1.53	3.05	9.2	18.4	55.2	33.0	66.0	198.0
Cu-D(2)	13.2	20.5	41.0	2.65	4.19	8.37	0.9	1.8	5.5	41.3	82.5	247.5

*Plant size in tons of copper processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Research Triangle Institute.

Arthur G. McKee and Co., Systems Study for Control of Emissions, Primary Nonferrous Smelting Industry, VII, Final report to National Air Pollution Control Administration, Contract PH86-65-85, June 1969.

Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Copper Industry, September 1962.

Fluor Utah Engineers and Contractors, The Impact of Air Pollution Abatement on the Copper Industry, April 1971.

Kennecott Copper Corporation, Copper Smelting Current Practices and Future Developments, AIME Annual Meeting, February-March 1971.

(b) Roaster(s) followed by the sintering machine(s) with the acid plant(s) receiving tail gas from the roaster(s),

(c) Roaster(s) followed by electrolytic purification with the acid plant(s) receiving the tail gas from the roaster(s).

For the purpose of this analysis, these three plant types were termed Zn-A, Zn-B, and Zn-C, respectively. Each zinc smelter in the plant inventory has been identified as being one of the three plant types. The combination roaster-sinterer emits a tail gas stream with an SO_2 concentration of 2 to 2.5 percent, This concentration is too low to be used as input to a sulfuric acid plant. In plants with a separate roaster and sintering machine, the roaster accounts for practically 100 percent of the SO_2 emitted. However not all roasters can be controlled with acid plants. Older Ropp-type roasters issue a gas stream with an SO_2 concentration less than 1 percent. There is, however, only one plant that presently employs Ropp-type roasters and this plant is expected to close by 1975; it has not been included in this analysis. All other roasters can be and are presently controlled by single contact sulfuric acid plants.

Control alternatives for the roaster-sintering machine included replacing the downdraft machine with an updraft machine which emits two off-gas streams One stream, which contains about 85 percent of all the sulfur emitted, has an SO_2 concentration. The rich gas stream is amenable to control by an acid plant. The other alternative is to replace the existing downdraft machine with a recirculating updraft machine with a single off-gas stream having an SO_2 concentration of about 5 percent. This single stream may then be input into an acid plant.

In plants with a roaster and an acid plant, there are two alternatives. One is to convert the single contact plant to a double contact plant thus increasing the conversion of SO_2 + SO_3. The other alternative is to add a Wellman Scrubber to treat the tail gas of the acid plant. The Wellman process not only scrubs the SO_2 out of the acid plant tail gas, but also upon regeneration yields a high SO_2 concentration stream which can be used as input to the acid plant; thus, like the double contact process, the Wellman process increases the effective yield of the acid-making process. These alternatives are summarized in table D.8. Table D.9 summarizes the

Table D.8. Sulfur emission control alternatives for zinc smelters

Plant type	Alternative	Description	Removal efficiency (percent)
Zn-A	1	Convert to updraft sintering and place acid plant on rich stream from sinter.	85.3
	2	Convert sintering machine to recirculating updraft sintering with acid on entire off-gas stream.	96.0
Zn-B	1	Add double contact to present acid plant.	99.0
	2	Add Wellman Scrubber to present acid plant.	99.5
Zn-C	1	Add double contact to present acid plant.	99.7
	2	Add Wellman Scrubber to present acid plant.	99.9

Source: Research Triangle Institute.

Table D.9. Sulfur emission control costs for zinc smelters

Control alternative by unit process	Control costs (million dollars)						Annual emissions after control (tons)			Annual additional recovered sulfur after control† (tons)		
	Investment			Annualized								
	100*	350*	600*	100*	350*	600*	100*	350*	600*	100*	350*	600*
Zn-A(1)	$3.9	$ 8.6	$12.1	$0.548	$1.300	$1.890	2,772	9,669	16,566	15,048	52,701	90,354
Zn-A(2)	5.3	11.7	16.4	0.717	1.702	2.468	759	2,460	4,521	17,259	60,390	103,521
Zn-B(1)	0.262	0.556	0.768	0.073	0.160	0.225	129	455	779	436	1,525	2,614
Zn-B(2)	0.320	0.679	0.938	0.095	0.226	0.328	96	337	574	469	1,643	2,812
Zn-C(1)	0.262	0.556	0.768	0.073	0.160	0.225	50	172	294	442	1,544	2,647
Zn-C(2)	0.320	0.679	0.938	0.095	0.226	0.328	23	86	149	465	1,630	2,795

*Plant size in tons of zinc processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Research Triangle Institute.

Arthur G. McKee and Co., Systems Study for Control of Emissions, Primary Nonferrous Smelting Industry, VII, Final report to National Air Pollution Control Administration, Contract PH86-65-85, June 1969.

Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Zinc Industry, September 1962.

costs and emissions associated with each control alternative for selected plant sizes.

D.2.3. Lead Smelters

Lead smelters can be categorized into three plant types:

(a) Plants with downdraft sintering machines and no acid plant,

(b) Plants with updraft sintering machines and no acid plant,

(c) Plants with updraft sintering machines with an acid plant on the strong (high SO_2 concentration) off-gas stream only.

These plant types have been given the abbreviated designations Pb-A, Pb-B, and Pb-C, respectively. Each lead smelter in the plant inventory has been identified as being one of the three plant types.

The downdraft machines emit an off-gas stream with an SO_2 concentration too low to be used as input into an acid plant. Updraft machines emit two gas streams one, the so-called rich gas stream, is amenable to control by an acid plant; the lean gas stream is not. The alternatives selected for this study are summarized in table D.10.

D.2.4 Emissions Reductions and Costs,

Industry cost of control functions have been developed based on the costs and effectiveness of the control alternatives costed above and a listing of the nation's smelters which includes relevant process parameters for emissions and control cost estimation. The smelter size distribution is

Table D.10. Sulfur emission control alternatives for lead smelters

Plant type	Alternative	Description	Removal efficiency (percent)
Pb-A	1	Downdraft machine replaced with an updraft type and acid plant installed on rich SO_2 stream.	84.6
	2	Updraft machine of recirculating type with an acid plant on combined sinter off gas.	94.9
	3	Updraft sintering machine and acid plant on rich stream and limestone scrubber on lean stream.	96.3
Pb-B	1	Acid plant on rich stream.	84.6
	2	Weak sinter gas, recirculated and acid plant on combined off gas.	94.9
	3	Acid plant on rich stream and limestone scrubber on lean stream.	96.3
Pb-C	1	Limestone scrubber on lean stream.	96.3

Source: Research Triangle Institute.

Table D.11. Sulfur emission control costs for lead smelters

Control alternative by unit process	Control costs (million dollars) Investment			Annualized			Annual emissions after control (tons)			Annual recovered sulfur after control† (tons)		
	100*	350*	600*	100*	350*	600*	100*	350*	600*	100*	350*	600*
Pb-A(1)	$2.760	$6.080	$ 8.540	$0.589	$1.517	$1.829	1,274	4,455	7,623	6,996	24,486	41,976
Pb-A(2)	3.650	8.040	11.290	0.626	1.596	1.939	426	1,485	2,544	7,821	27,423	47,025
Pb-A(3)	3.750	8.260	11.590	1.012	2.446	3.129	317	1,069	1,832	6,996	24,486	41,976
Pb-B(1)	1.180	2.600	3.650	0.431	0.951	1.340	1,274	4,455	7,623	6,996	24,486	41,976
Pb-B(2)	2.070	4.560	6.400	0.468	1.030	1.450	426	1,485	2,544	7,821	27,423	47,025
Pb-B(3)	2.170	4.780	6.710	0.854	1.880	2.640	317	1,069	1,832	6,996	24,486	41,976
Pb-C(1)	0.990	2.180	3.060	0.421	0.928	1.300	317	1,069	1,832	0	0	0

*Plant size in tons of lead processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Research Triangle Institute.

Arthur G. McKee and Co., Systems Study for Control of Emissions, Primary Nonferrous Smelting Industry, VII, Final report to National Air Pollution Control Administration, Contract PH86-65-85, June, 1969.

Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Lead Industry, September 1962.

shown in tables D.12 through D.14. These functions are minimum cost functions for achieving sulfur emissions from the primary nonferrous smelting industries.

Using lead smelters as an example, a 100 ton per day, type A smelter can reduce emissions to 1,274 tons annually for an annualized cost of $589,000 (table D.11). The precontrol level of emissions is 8,273 tons of sulfur annually (i.e. 1,274 ÷ (1 - removal efficiency of 84.6 percent)). A smelter would control sulfur emissions by installing an acid plant where the cost of control plus the tax rate times the remaining emissions was less than the tax times the uncontrolled emissions. For this example smelter, that would be for tax rates greater than 4 cents per pound of sulfur emissions since:

$589,000 + TAX (1,274) = TAX (8,273)

TAX = $84 per ton or 4 cents per pound

where

X = tax rate per ton of sulfur emitted.

The long-run industry total and marginal unit costs of emissions reductions are shown in figures D.1 and D.2. Because of the absence of technology that could provide intermediate levels of control at acceptable costs and the limited number of plants, the total cost function (LTC) is probably discontinuous throughout all but the upper ranges. The marginal costs (LMC) rise slowly until emissions reductions of about 94 percent (1.5 million tons) are reached. After that point, marginal costs rise quite sharply.

Table D.12. Size distribution of copper smelters

Capacity*	Plant type			
	Cu-A	Cu-B	Cu-C	Cu-D
0 - 99	-	-	-	1
100 - 199	-	-	-	-
200 - 299	4	-	-	2
300 - 399	2	-	1	1
400 - 499	-	-	-	1
500 - 599	-	-	-	2
700 - 799	-	1	-	-

Plant size in tons of copper processed per day.

Source: Research Triangle Institute.

Table D.13. Size distribution of zinc smelters

Capacity*	Plant type		
	Zn-A	Zn-B	Zn-C
100 - 199	-	1	1
200 - 299	1	-	1
300 - 399	-	-	1
400 - 499	-	1	-
500 - 599	-	1	-

*Plant size in tons of zinc processed per day.
Source: Research Triangle Institute.

Table D.14. Size distribution of lead smelters

Capacity*	Plant type		
	Pb-A	Pb-B	Pb-C
100 - 199	1	1	-
200 - 299	-	1	-
300 - 399	-	-	1
400 - 499	-	-	1
800 - 899	-	-	1

*Plant size in tons of lead processed per day.
Source: Research Triangle Institute.

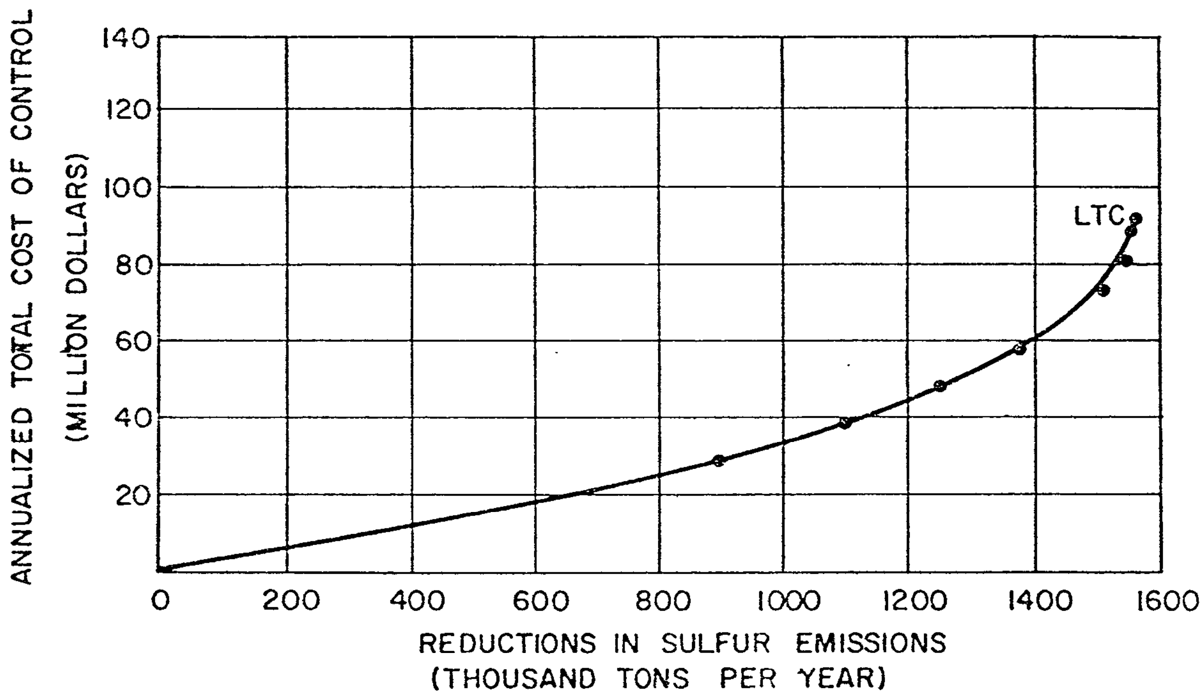

Figure D.1. Total cost* of reductions in sulfur emissions: primary nonferrous smelters--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

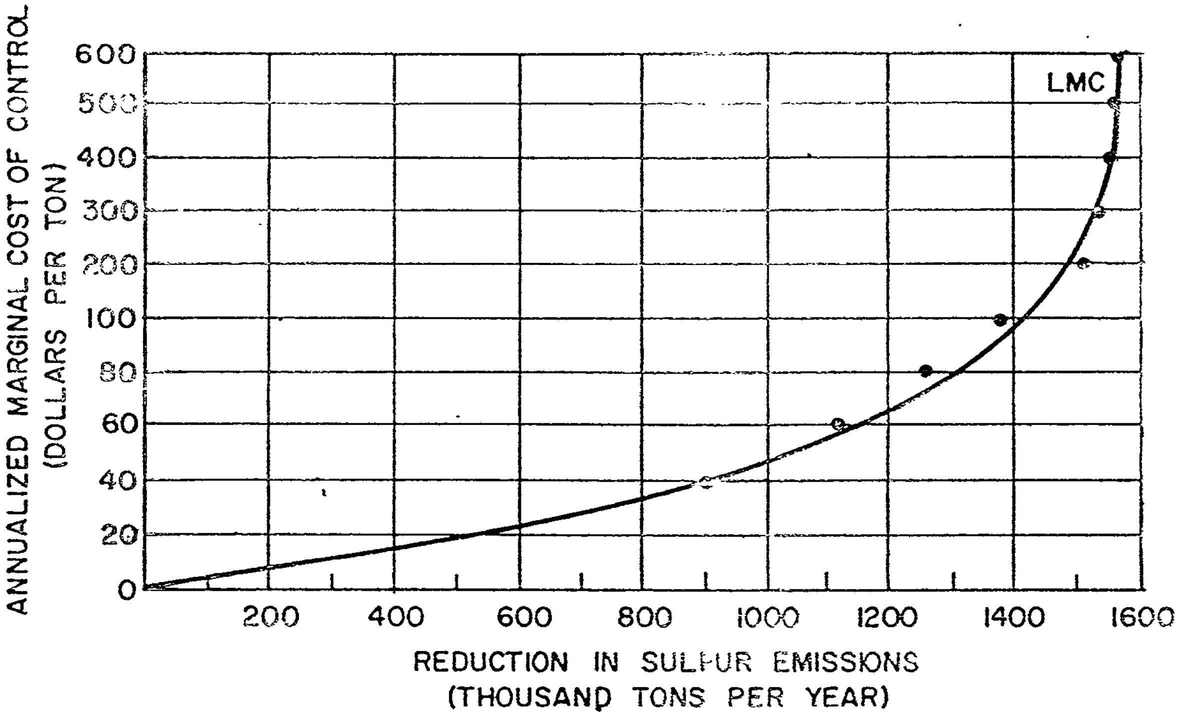

Figure D.2. Marginal cost* of reductions in sulfur emissions: primary nonferrous smelters (*does not include emissions tax payments) (Source: Research Triangle Institute).

Appendix E: THE PROJECTED MARKET FOR RECOVERED SULFUR

E.1 Introduction

Several of the alternatives for controlling sulfur oxide emissions result in the recovery of marketable sulfur or sulfuric acid. The future market for those products may influence the choice of emissions control and the net cost to the industries controlling sulfur emissions, Therefore, it is desirable to examine briefly the market for sulfur.

Sulfur is a naturally occurring inorganic mineral with many industrial uses, especially in the form of sulfuric acid. The largest use is in fertilizer production which consumes about one-half of all production. To a lesser extent, it is also used in making steel, rayon, paper, nonferrous metals, and chemicals,

E.2 Major Sources of Sulfur

Sulfur is mined from subterranean sulfur domes (native sulfur) and is also produced as a byproduct of some industrial processes, principally in the refining of sour oil and gas. Imports, primarily from Mexico and Canada, also supply portions to the U.S. market,

The share of the U.S. sulfur market enjoyed by native sulfur has been declining fairly regularly over the past 20 years. The smelter acid share has been fairly constant, The decline in the native sulfur share results from an increase in byproduct sulfur recovery which has increased over fourfold in the last 20 years.

E.3 Consumption of Sulfur

The apparent consumption of sulfur in the United States has been increasing about 2.8 percent annually since 1950, reaching 10.0 million tons* in 1970.†

The demand for sulfur is derived from the demand for fertilizers and other products for which sulfur is a major component. In the past,

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*Sulfur quantities are usually measured in long tons (2,200 pounds); however, for purposes of consistency within this report all figures here have been converted to the more common short ton (2,000 pounds).

†U.S. Department of Interior, Bureau of Mines, Minerals Yearbook, 1970, Washington, D.C., p. 1054.

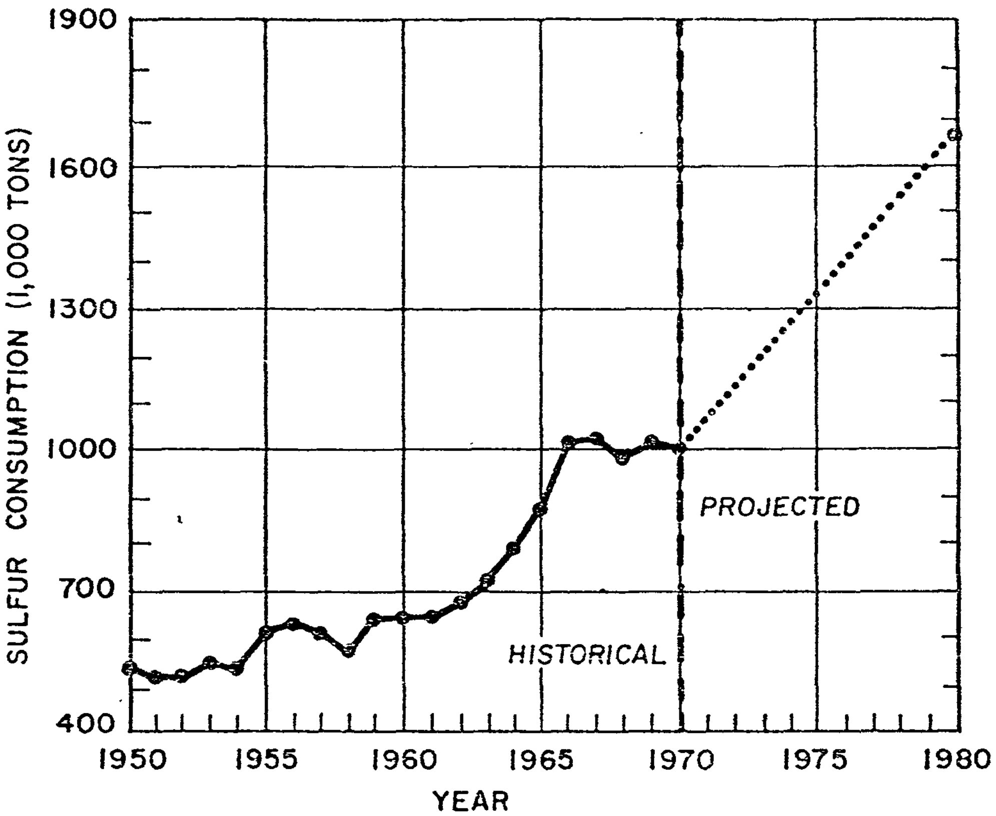

Figure E-1. Sulfur consumption trends (Source: Historical data, Department of the Interior: Projections, Research Triangle Institute).

there has been a close relationship between gross national product (GNP) and sulfur consumption in the United States. Given the inelastic demand for sulfur at the low prices, as reported in several studies,* and the prospects for continued depressed prices, a reasonable projection of sulfur demand for use in this study was obtained by extending this historical relationship to 1980. Based on a projected 1980 GNP of $1,155 billion, sulfur consumption in 1978 is expected to be 15.1 million tons (see fig. E.1), 5.1 million tons above the 1970 estimate. With the increasing production of sulfur on a worldwide basis, it appears unlikely that the export demand will grow. Therefore,

*M. H. Farmer and R. R. Bertrand, Long-range Sulfur Supply and Demand Model, Report GRU.1GM.71. Esso Research and Engineering Company, Linden, New Jersey, November 1971, p. 6.

†U.S. Department of Labor, Bureau of Labor Statistics, Patterns of U.S. Economic Growth (1980 projections of final demand, interindustry relationships, output, productivity, and employment), Bulletin 1672, Washington, D.C., U.S. Government Printing Office, 1970, p. 43.

Table E.1. Projected sulfur emissions—1978*

Emissions source	Sulfur emissions (thousand, tons)
Steam electric plants	11,396
Area sources	5,679
Petroleum refineries	772
Sulfuric acid production	376
Primary nonferrous smelters	1,650
	19,873

*Assuming only the implementation of the New Source Performance Standards.

Source: Research Triangle Institute.

the projected U.S. consumption is expected to reasonably reflect the total market for U.S. sulfur.

As shown in table E.1, the projected 1978 uncontrolled sulfur emissions from the major sources under consideration in this study are about 20 million tons, an amount in excess of the projected production of sulfur. Any significant reduction in sulfur emissions and recovery and sale of sulfur could account for a substantial share of the projected growth in production. Such an eventuality will have a depressing effect on sulfur prices.

E.4 Prices of Sulfur

The price of sulfur is a function of the interrelationship of sulfur demand and supply. The demand for sulfur is derived from the demand for products where sulfur is used as a raw material. The supply of sulfur is based not only on the costs of mining sulfur but also on the availability of recovered sulfur which will be recovered, regardless of price, and sold for whatever price it will bring.

Figure E-2 shows the trend in sulfur prices over the past 20 years. For a long period beginning in 1947 and extending through 1966, sulfur prices edged up about 2.4 percent annually. However, beginning in December 1966, sulfur prices began to rise rapidly, averaging a 2.7

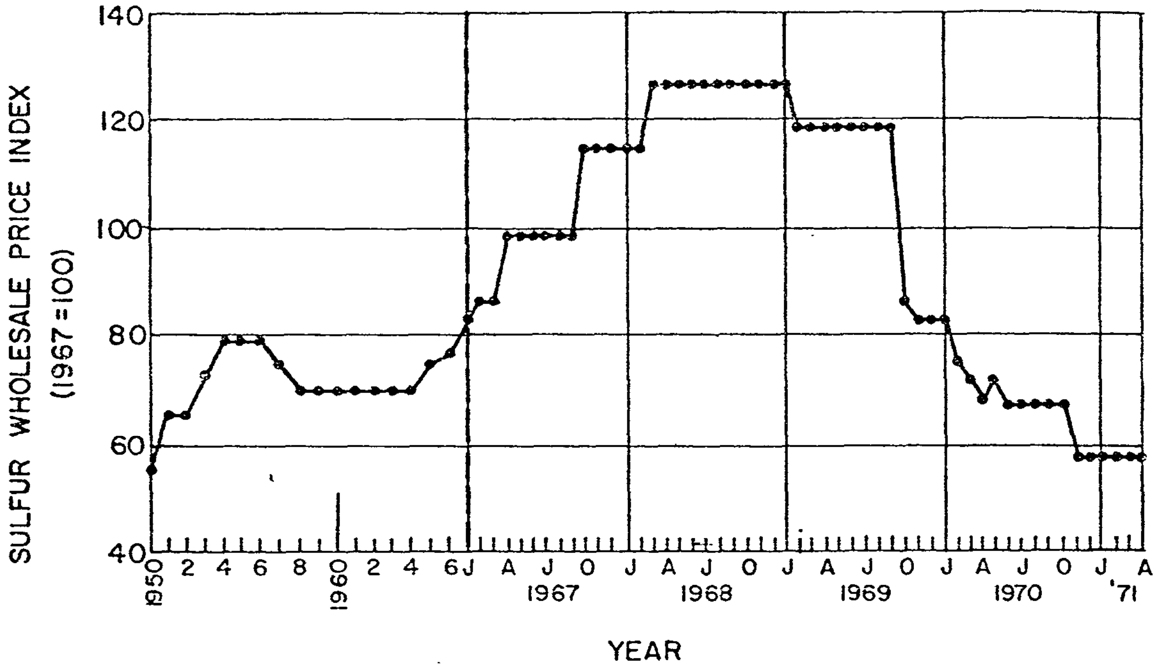

Figure E.2. Sulfur price index (Source: Department of Labor).

percent increase per month for the next 15 months. Between September and October of 1967, prices jumped 16 percent. In 1968, prices were relatively stable. Then early in 1969, they began to decline rather precipitously, finally reaching a level in 1971 of half their 1969 high.

The collapse of sulfur prices in 1969 is attributed to several causes, among them being:* (1) the drop in fertilizer demand due to overcapacity, (2) the expansion of pyrite roasting capacity in Europe, (3) the start-up of a large Frasch process operation in west Texas, (4) the expansion of modified Frasch process production in Poland, (5) expanded recovery of elemental sulfur by desulfurization of petroleum, (6) the increase in the recovery of acid from smelter gas, and (7) the U.S. business recession.

Published data on absolute value of current prices is unavailable because the Frasch process producers stopped publishing prices in 1969. However, by using the Bureau of Labor Statistics price index

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*M. H. Farmer and R. R. Bertrand, Long-range Sulfur Supply and Demand Model. Report GRU.1GM.71, Esso Research and Engineering Company, Linden, New Jersey, November 1971, p. 3.

with the 1968 price of $38 per ton for crude domestic, dark, bulk sulfur, as reported in the Oil, Paint, and Drug Reporter the 1971 price can be estimated as about $20 per ton. It appears that $20 per ton represents the low end of the price range for Frasch sulfur; prices may be as much as $14 higher depending on the port of delivery. Recovered sulfur prices are a different matter. One Southwest oil refiner quotes prices of $14 to $25 per ton f.o.b. the refinery.* Many large buyers, however, are willing to pay a premium for Frasch process sulfur to obtain needed quantities and to help assure future availability.

It appears that future prices will continue to be depressed even without additional recovery by the large increases expected in Canadian capacity and continued growth in the amount recovered, especially from sour gas and from smelter gas. Furthermore, if ocean shipment of liquid sulfur becomes a reality, Canadian sulfur may be competitive with domestic sulfur in the largest U.S. sulfur market, the Florida phosphate industry.

The long-run upper limit on the price of sulfur is determined by both the cost of obtaining sulfur from its various sources and by the cost of alternative manufacturing processes that avoid the use of sulfur.† One report placed the costs of sulfur production between $10 and $43 per ton depending on source (see table E.2). The lower limit is indeterminate.

In summary, because of the downward pressures on sulfur prices and the likelihood of additional recovery of sulfur from controlling sulfur emissions, we believe that valuing the recovered product at a high price appears unwarranted. Most optimistically, the recovered product could be sold at prevailing market prices. This outcome would appear reasonable only if the product is not recovered in amounts large enough to significantly increase supplies and cause prices to decline. At the other extreme, if increased recovery of sulfur products results in substantial increases in supply without significant increases in quantity demanded, then the total value of sales may actually decrease.

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*C. W. Winton, "Dark Cloud on Sulfur's Horizon," Chemical Week, February 10, 1971, p. 31.

†M. C. Manderson, "The Sulfur Outlook," Chemical Engineering Progress, November 1968, pp. 47-53.

Table E.2. Sulfur production costs by source

Source	Cost per long ton
Frasch	
Low cost	$10
Medium cost	15
High cost	23
Sour gas	
Natural gas	15
Refinery	20
Smelter gas	18
Pyrites	35
Gypsum	35
Other native	35
Utility stack gas	43

Source: M. C. Manderson, "The Sulfur Outlook," Chemical Engineering Progress, November 1968, pp. 47-53.

This is a reasonable possibility given the inelastic demand for sulfur. Finally, in industries that use sulfur as an input and that recover more of the product due to a tax on their emissions of sulfur, the recovered product may be used as a substitute for purchased sulfur. In this case, the recovered sulfur should be valued at prices reflective of the sulfur cost savings. In many cases, this possibility appears most likely. For this analysis of a tax on sulfur emissions, the approximate current price, $20 per ton, and lower prices more reflective of the likely increase in sulfur supply, $10 and $0, have been selected as alternative future values for the marketable, recovered sulfur and for sulfuric acid.

Appendix F: THE EFFECT OF THE CORPORATE TAX STRUCTURE ON THE PROJECTED EMISSION LEVELS.

The purpose of this appendix is to analyze the effect of ignoring corporate income taxes and tax preferences on the levels of emission reductions that are projected in this study.*

The following variables will be used:

θ = corporate income tax rate, $(0 < \theta < 1)$;

ϕ = sulfur tax rate, dollars per pound;

E_j = sulfur emissions per period under j control option $(j=1, \ldots, m)$ pounds per year;

K_j = investment cost of the j^{th} control option, dollars;

V_j = variable cost per period under the j control option;

d = depreciation rate per period, $(0 < d < 1)$;

n = planning horizon, in years;

r = cost of capital;

PV = present value of the anticipated cash outlay over the period n, in dollars.

Assume that the emissions tax payments (ϕE_j) are fully deductible from gross income and that the plant seeks to minimize the present value of its anticipated cash outlays for sulfur waste management. Under these assumptions the plant saves θ dollars in income taxes for each dollar it spends on emissions taxes and variable control costs, and for each dollar in depreciation it can charge against current gross income. Consequently, a dollar spent on emission control does not actually cost the plant a dollar; rather, it costs $(1-\theta)$ dollars. These ideas can be expressed symbolically,

The total emission-control-related variable operating costs (TVC) for a plant will be the sum of the variable costs (V_j) associated with the j^{th} control option and total emission taxes which equal the tax rate (ϕ) times the emissions (E_j) that would remain after the implementation of j^{th} control option:

$$TVC_j = V_j + \phi E_j \qquad j = 1, \ldots, m \qquad (1)$$

*See Richard D. Wilson and David W. Minnotte, "Government/Industry Cost Sharing for Air Pollution Control," Journal of the Air Pollution Control Association, XIX, No. 10 (October 1969) pp. 761-766, for a detailed discussion, with examples, of these tax considerations.

Total emission-control-related depreciation expenses (DPR_j) during any period will be:

$$DPR_j = d\ K_j \qquad j = 1, \ldots, m \qquad (2)$$

The model used in this study assumes that TVC_j is constant over time and that emissions (E_j) associated with the j^{th} option are known. Consequently, during the first year of operation with the control equipment in place, the plant must make a cash outlay for the capital cost of the device (if any) and for the variable costs associated with the control option; during each succeeding period, outlays are required for only the variable costs. The discounted present value of the <u>costs</u> associated with the j^{th} control option is:

$$DPV(costs)_j = \left[\sum_{t=0}^{n} \left(\frac{1}{1+r}\right)^t (V_j + \phi E_j)\right] + K_j \ . \qquad (3)$$

The discounted cash value of the <u>benefits</u> of the j^{th} control option is the discounted stream of income tax savings which is:

$$DPV(benefits)_j = \sum_{t=0}^{n} \left(\frac{1}{1+r}\right)^t \theta(V_j + \phi E_j + d\ K_j) \ . \qquad (4)$$

The method of choosing among control options in this study was equivalent to choosing the option for which Eq. 3 was minimized.* However, the income tax consideration implies that savings associated with control options are not considered under the criterion of Eq. 3. The rational manager will consider net costs; i.e., the difference between Eqs. 3 and 4:

$$DPV(net\ cost)_j = (1-\theta)\left[\sum_{t=0}^{n}\left(\frac{1}{1+r}\right)^t (V_j + \phi E_j)\right] + K_j\left[1-\theta\left\{d\sum_{t=0}^{n}\left(\frac{1}{1+r}\right)^t\right\}\right] \qquad (5)$$

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*To see this, divide both sides of Eq. 3 by the discount factor. This yields the annualized expenditure whose present value is given by Eq. 3:

$$\text{Annualized Cost}_j = V_j + \phi E_j + K_j \Big/ \sum_{t=0}^{n}\left(\frac{1}{1+r}\right)^t \ .$$

The method of this study was to predict that plants would choose the control option which minimizes annualized cost; formally equivalent to choosing the option which minimizes Eq. 3.

If Eq. 5 is divided through by $(1-\theta)$, it is different from Eq. 3 only in the coefficient on K_j. Given that the annual depreciation rate, d, is the reciprocal of the number of years, n, over which the equipment is depreciated, it is readily obvious that that coefficient is greater than unity.*

Some tentative conclusions seem warranted in comparing Eqs. 3 and 5. First, all costs appear to be overstated by using Eq. 3. Because of the considerations mentioned in the foregoing paragraph, the overstatement would appear to be somewhat less than a factor of $1/(1-\theta)$. For example, if the corporate. income tax rate is 50 percent (e=0.5), the overstatement of costs predicted by Eq. 3 would be somewhat less than a factor of 2. However, Eq. 5 also indicates that the effective emissions tax rate, ϕ, is overstated by a factor of $1/(1-\theta)$ in Eq. 3 since all emissions tax payments are deductible expenses for income tax purposes. Consequently, the behavioral predictions of this report are probably not too affected, since both the effective tax rate and net costs were overstated by about the same factor.

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*Define α $(0 \le \alpha \le 1)$ as

$$\alpha = d \sum_{t=0}^{n} \left(\frac{1}{1+r}\right)^t \quad .$$

Then the coefficient, a, on K_j in Eq. 5 is

$$a = \frac{1-\theta\alpha}{1-\theta} \quad .$$

If $\alpha=1$, $a=1$. If $\alpha=0$, $a=1/(1-\theta)$. Therefore, if the income tax rate is 50 percent $(\theta=0.5)$, the upper bound on a is 2.